STATE OF MAINE
PUBLIC UTILITIES COMMISSION

Docket No. 2001-232

February 15, 2002

MAINE PUBLIC UTILITIES COMMISSION
Investigation of Central Maine Power Company's
Stranded Cost Revenue Requirement

ORDER APPROVING
STIPULATION

WELCH, Chairman; NUGENT and DIAMOND, Commissioners

## I. SUMMARY

In this Order we approve a Stipulation entered into between Central Maine Power Company (CMP or Company), the Office of Public Advocate (OPA) and the Industrial Energy Consumers Group (IECG) which establishes CMP's stranded cost revenue requirement for a 3-year period. Under the terms of the Stipulation which we approve, stranded cost rates for the Company's residential and small commercial customers will be reduced by approximately 25%, the Company's largest industrial customers will continue to receive rate mitigation although at a reduced level to offset high generation costs, and stranded cost rates for all other customers will remain level during the 3-year period.[1]

## II. PROCEDURAL HISTORY

See Appendix A.

## III. BACKGROUND

On March 1, 2000, Maine consumers were provided with the opportunity to purchase generation services from the competitive market and as of that date the generation portion of electricity service was no longer subject to rate regulation in Maine. As a part of the Restructuring Act, the Commission was required to determine and permit recovery of each utility's stranded costs, defined to be the "legitimate, verifiable and unmitigable costs made unrecoverable as a result of the restructuring of the electric industry … ." 35-A M.R.S.A. § 3208.

In *Public Utilities Commission, Investigation of Central Maine Power Company's Stranded Costs, Transmission and Distribution Utility Revenue Requirements and Rate Design,* Docket No. 97-580 (CMP's so-called

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[1] Commissioner Diamond votes to reject the Stipulation for reasons explained in his attached Dissenting Opinion.

"megacase"), the Commission established transmission and distribution (T&D) rates which reflected a 2-year stranded cost revenue requirement. The 2-year period was chosen to coincide with the period of time for which CMP had sold its non-divested generation asset entitlements pursuant to Chapter 307 of the Commission's Rules. By way of orders dated March 26, 2001 and May 3, 2001, we reduced CMP's T&D rates by .8¢/kWh for those customers that fell within the Company's medium and large standard offer classes to mitigate the impact of significant increases in generation prices whether from standard offer service or competitive providers. *Public Utilities Commission, Investigation of Central Maine Power Company's Stranded Costs, Transmission and Distribution Utility Revenue Requirements and Rate Design,* Docket No. 97-580, Order (March 26, 2001) and Order on Reconsideration (May 3, 2001). The .8¢/kWh mitigation was to be funded through an allocation of the Company's Asset Sale Gain Account (ASGA).[2] The mitigation went into effect on April 15, 2002 and will expire on February 28, 2002.

Given the pending expiration of CMP's initial sale of entitlement output, the Commission initiated this case on May 8, 2001. As discussed in Section II, *infra.*, since much of the information needed to decide this case was not available at the time we initiated it, the schedule was segmented into several phases: the initial phase facilitated the identity of major issues; Phase II contained the utility sales forecast as well as projected rates based on illustrative Chapter 307 bid information; and Phase III contained actual rate recommendations using the Chapter 307 bid information.

On September 19, 2001, the Commission accepted a contingent standard offer bid for CMP's residential and small commercial classes. As part of the decision to accept a contingent standard offer bid, an affiliate of the winning standard offer bidder also purchased the CMP non-divested entitlements for a three-year period.[3] *Public Utilities Commission, Standard Offer Bidding Process,* Docket No. 2001-399, Order (Sept. 18, 2001). As a condition of the winning bid, the price that the winning bidder is to pay for the power supply entitlement was to be protected from disclosure until January 1, 2002.

On October 3, 2001, CMP submitted its Phase II filing, which contained its stranded cost revenue requirement proposals and calculations using proxy prices established by the Examiner in a Procedural Order dated September 28, 2001. On November 13, 2001, the OPA and the IECG filed testimony in response to the

[2] The ASGA is a regulatory liability on the Company's books resulting from the over-book proceeds received from CMP's divestiture of its generation assets.

[3] In its Order on Reconsideration in Docket No. 2001-399 (Jan. 11, 2002), the Commission explained why it found that selling the non-divested generation asset entitlements as part of the standard offer process without a concurrent stand-alone Chapter 307 process was reasonable.

Company's case. On November 14, 2001, the Commission's Advisory Staff filed its Phase II bench analysis. The Intervenors' testimony and the Staff's Bench Analysis raised the following issues regarding the Company's filing: sales forecast; revenue from non-core customers; revenue from the Hydro-Quebec (HQ) tie-line; treatment of variations in stranded costs resulting from Qualifying Facility (QF) forced outages; treatment of distributions received by Maine Yankee from Nuclear Electric Insurance Limited (NEIL); the appropriate return on equity (ROE) level to be applied to CMP's Connecticut Yankee investment; treatment of the standard offer over-collected balance; and allocation of stranded costs among the customer classes. On December 7, 2001 the Company filed its rebuttal case in response to the Intervenors' and Staff's filings.

On December 11, 2002 the Examiner was informed by counsel for CMP that the parties had reached an agreement in principle to settle this matter. A case conference to discuss the processing of the Stipulation was held on December 12, 2001. At such time the Commission's Advisory Staff informed the parties that it opposed the Stipulation based on the parties' description.

On December 13, 2001, we received a Stipulation entered into between the Company, the OPA and the IECG which resolved all issues in this matter. The filing indicated that the other parties to the case, S.D. Warren, FPL Energy Maine, Inc. and Calpine Finance Construction Company, took no position regarding the proposed Stipulation. The parties agreed that the Advisory Staff would present its objections to the Stipulation to the Commission orally at the hearing on the Stipulation. A hearing on the Stipulation was held on December 18, 2002.

## IV. DESCRIPTION OF THE STIPULATION

Under the terms of the Stipulation, stranded cost revenue requirements and rates would be established for a 3-year period beginning March 1, 2002 and ending on February 28, 2005. During the three years, however, any person could petition the Commission after May 31, 2002 to adjust stranded costs for, among other things, variances between the sales forecast relied on to set rates here and actual sales. In addition, during the 3-year period, CMP agreed to file quarterly reports detailing the level of its electricity sales as well as the amount of stranded cost revenue recovered from both its core and non-core customers for both the preceding 3-month and 12-month periods.

The Stipulation used CMP's October 3, 2001 Phase II filing as its "base revenue requirement case." The following table summarizes the adjustments to the revenue requirement proposed by CMP in its Phase II filing as agreed to in the Stipulation:

| | **YEAR 1** | **YEAR 2** | **YEAR 3** |
|---|---|---|---|
| Adjustment for Diesel Deferral Increase | $621,000 | $606,000 | $607,000 |
| Extension of Recovery of RWS Buyout Costs | $784,000 | $725,000 | $666,000 |
| Estimate of HQ Tie-Line Revenue | $1,077,000 | $1,077,000 | $1,077,000 |
| Adjustment for Reduced Return of Conn. Yankee Investment | $380,000 | $321,000 | $278,000 |
| "Maine Yankee Adjustment" | $2,409,000 | $2,686,000 | $2,781,000 |
| Standard Offer Overcollection | $1,410,000 | $1,328,000 | $1,247,000 |

Based on the above adjustments, the agreed-to Year 1 revenue requirement is $133,705,000, Year 2 is $143,696,000 and Year 3 is $147,534,000. These amounts were subject to update to account for the actual revenue received under the contingent standard offer bid for the Company's non-divested entitlements. The stranded cost rates would be calculated using CMP's sales forecast adjusted for the removal of DSM in 2002, recognition of the effects of the current recession on current sales, and updates to the projected price of electricity. To stabilize customers' rates over the rate-effective period, the parties agreed to levelize stranded cost rates over the 3-year period by adjusting the amortization of the Asset Sale Gain Account.

Under the terms of the settlement, stranded costs would decrease from the levels set in Docket No. 97-580. The decrease would be allocated primarily to the residential and small commercial customer classes, which would receive approximately a 25% decrease from current stranded cost rate levels. A small portion of the stranded cost revenue decrease requirement would be allocated to the Company's IGS-S, IGS-P, LGS-S and LGS-P customers. In addition, the Stipulation provides that " in recognition of their current situation both within the Maine economy and their energy supply prices and contract terms," customers eligible for service under the Company's LGS-ST and LGS-T rates would receive mitigation of 4.5 mils per kilowatt hour ($.0045/kWh) for rates in effect during the period from March 1, 2002 through February 28, 2003. This mitigation could not in any case reduce any customer's stranded cost rate below zero.

The Stipulation also establishes a deferral mechanism for extraordinary variances in stranded costs as a result of changes in Qualifying Facility (QF) output. Under this mechanism, if stranded costs from any one of 13 large QF contracts listed in the Stipulation are outside a +/-3% dead band of a baseline level developed using historical output averages, the differences from the amounts set forth in the Stipulation are to be deferred with carrying costs for future recovery/reduction in rates.

The Stipulation also establishes a QF incentive mechanism to ensure that CMP has an adequate incentive to restructure QF contracts. Under this mechanism, when a QF contract is restructured, customers will receive 80% of the savings and CMP will retain 20% of the savings. When stranded costs are reset, stranded costs will include the post-restructuring QF costs plus CMP's 20% share of savings based on projections for that period. In the event that post-restructuring costs exceed pre-restructuring costs for any stranded cost ratesetting period, no savings (positive or negative) will be included.

Finally, the Stipulation agrees to a number of deferrals for later offset against the Asset Sale Gain Account, or inclusion in rates, for items which were not included in the determination of stranded costs in this proceeding.

## V. POSITIONS BEFORE THE COMMISSION

### A. The Opposition of the Advisory Staff

At the December 18, 2001 hearing, the Advisory Staff expressed its opposition to the Stipulation. The Advisory Staff's opposition is limited to the Stipulation's provision for the 4.5 mil rate mitigation provided to the LGS-T and LGS-ST classes.

The Advisory Staff argues that the stipulating parties have provided no basis for the extension of this benefit to these two customer classes. While the Commission last year had approved a mitigation program for all of CMP's medium and large standard offer customer classes due to the significant increase in generation costs, the logic for such a program no longer seemed to exist since generation prices were declining. To the extent that mitigation was warranted, it was not clear why such mitigation should be limited to LGS-T and LGS-ST customer classes since the core rates established by the Stipulation for these customer classes were already lower than the rates which would result from a straight application of the stranded cost allocation methodology approved by the Commission in Docket 97-580. This is in contrast to the core rates for other large customer classes (LGS-P, LGS-S, IGS-P, IGS-S) which exceed the rates which would result for a straight application of the Docket No. 97-580 cost allocation methodology. Thus, the Advisors argue that they can find no rational basis to support the design of this mitigation program, which would result in a reduction of approximately $7.4 million in the ASGA. The Advisors recommend that the Commission reject the rate mitigation proposal and thus the Stipulation.

The Advisory Staff also notes that given the disparate treatment between those classes which were represented (the LGS-T and LGS-ST) and those which were not represented (the IGS classes and other LGS classes), there is at least an appearance, if not a reality, of disenfranchisement of certain customers under the Stipulation. This, according to the Advisory Staff, provides another reason to reject the Stipulation.

B. Response of the Stipulating Parties

The Company argues that in deciding whether a Stipulation is in the public interest the entire Stipulation must be considered as a package. In looking at the package, it is necessary to look at the mitigation in the context of the benefits which CMP believes are provided to the broad body of ratepayers (e.g. the Maine Yankee adjustment, sales forecast adjustment). Under the terms of the Stipulation, the Company's largest group of customers, the residential and small commercial classes, will receive a substantial reduction in their stranded cost rates. On a bundled basis these customers will only see approximately a 3% increase in their total bill on March 1, 2002. This is quite moderate given the substantial increase in standard offer prices that these customers will realize.

The IECG argues that in implementing restructuring the Commission has not relied on cost allocation methodology in setting T&D rates, but instead has based T&D rate design on the "top-down" approach which looked at the overall (bundled) rate customers would be paying in setting T&D rates. Second, the IECG argues that when the $7.4 million cost of the 4.5 mil mitigation is looked at in context of the allocation of other benefits made under the terms of the Stipulation, it is clear that the LGS-T and LGS-ST classes have not received a disproportionate share of benefits.

In this regard, the IECG notes that the cost of saving the Engage-Energy Atlantic standard offer contract under the first "linked" standard offer was assigned to all classes and not just to residential and small commercial customers who received the benefit of the linked bid. In addition, the over-collection of standard offer costs from large and medium customers was allocated to all customers and not to just those classes who overpaid. The residential and small commercial classes will also receive the overwhelming majority, approximately $17 million, of the reduction in stranded costs under the Stipulation. Finally, the IECG argues these customer classes have also received a benefit through a reduction in the overall bundled price of electricity through the linked bid.

The IECG claims that a majority of CMP's LGS-T and LGS-ST customers have signed multi-year generation contracts that will run through 2002. Without further rate mitigation, LGS-T and an LGS-ST customers who have long-term generation contracts would see about a 14 to 15 percent increase compared to pre-restructuring rates. These customers are some of the state's largest employers and electricity represents a large portion of their overall costs. Since these firms operate in very competitive international markets, increases in electricity costs cannot simply be passed on.

The Company argues that the 4.5 mil mitigation could be viewed as a transition out of the larger mitigation program initiated by the Commission. The stipulating parties note that while the MGS, IGS, LGS-S and LGS-P customers will not receive any mitigation, a majority of the customers in these rate classes are on the standard offer and, thus, will see a decrease in their bundled bill given the projected decrease in standard offer prices.

The OPA notes that one key benefit of the 4.5 mil mitigation program provided by the Stipulation is to avoid a debate in the Legislature for a much more far-reaching mitigation program in proposed legislation that the Legislative Council has permitted for consideration during the second regular session of the 120th Legislature.

## VI. DECISION

As we have now stated on numerous occasions, to approve a Stipulation the Commission must find that:

1. the parties joining the Stipulation represent a sufficiently broad spectrum of interests that the Commission can be sure that there is no appearance or reality of disenfranchisement;

2. the process that led to the Stipulation was fair to all parties; and

3. the stipulated result is reasonable and not contrary to legislative mandate.

*See Central Maine Power Company, Proposed Increase in Rates,* Docket No. 92-345(II), Detailed Opinion and Subsidiary Findings (Me. P.U.C. Jan. 10, 1995), and *Maine Public Service Company, Proposed Increase in Rates (Rate Design),* Docket No. 95-052, Order (Me. P.U.C. June 26, 1996).

We have also recognized that we have an obligation to ensure that the overall stipulated result is in the public interest. *See Northern Utilities, Inc., Proposed Environmental Response Cost Recovery,* Docket No. 96-678, Order Approving Stipulation (Me. P.U.C. April 28, 1997). We find that the proposed Stipulation in this case meets all of the above criteria.

In this case, the Stipulation was entered into by the Company, the OPA and the IECG. No other intervenor opposes the Stipulation. We find that the stipulating parties represent a sufficiently broad spectrum of interests to ensure that there was no appearance or reality of disenfranchisement. In this case, unlike other cases in recent history where we have approved stipulations, the Stipulation is opposed by our Advisory Staff. The Advisory Staff's role, however, is not to represent any particular group, but to advise the Commission on the merits of the case. Therefore, the Advisory's Staff's objection does not cause us to change our conclusion that the parties to the Stipulation represent a sufficiently broad spectrum of interests to satisfy the first criterion.

There has not been any indication given by any intervenor or the Advisory Staff in its objection that the process in this matter was anything but fair. We thus find that our second criterion has also been satisfied, and we address the Advisory Staff's objection in terms of whether the Stipulation is reasonable and in the public interest.

In deciding whether a Stipulation is fair and consistent with the public interest, the entire stipulation must be considered as a package. Whether we disagree with a particular stipulation provision or would have come up with a different resolution were we deciding the case after litigation is not the question. Central Maine Power Company, Request for Approval of Alternative Rate Plan (Post-merger) "ARP 2000," Docket No. 99-666, Order Approving Stipulation at (November 16, 2000). The question is whether the particular proposal before us is reasonable and consistent with the public interest. *See Docket No. 92-345 (Phase II), supra*., Order at 3. In deciding this question, any detriments which have been raised must be weighed against the benefits of the Stipulation.

A general consensus has developed that the benefits of the Stipulation, other than the mitigation provision, are considerable. The Stipulation resolves all stranded cost revenue requirement issues. The parties and the Advisors dispute many difficult revenue requirement issues, with many millions of dollars at stake. The Stipulation resolves these issues involving considerable dollars (resulting in an annual revenue requirement decrease) in a way that all parties find satisfactory, saving all parties (and the Commission) considerable litigation costs and eliminating the risk to all parties that the litigated outcome may be unsatisfactory. Importantly, the Advisors concur that the Stipulation reasonably resolves the revenue requirement issues.

Moreover, rate design issues other than rate mitigation were also disputed. The Stipulation allocates to all T&D rate classes the cost of payments to Engage Energy that resolved a dispute pertaining to the provision of residential and small non-residential standard offer service. The overcollection associated with CMP's provision of standard offer service to the medium and large non-residential classes is also allocated to all T&D rate classes. The majority of the overall revenue requirement decrease is allocated to the residential and small non-residential classes. The IECG correctly points out that, standing alone, these other rate design issues may be resolved differently if the case is fully litigated.

Thus, we must consider the Advisory Staff's recommendation that the stipulated result is unreasonable because of the LGS-T and LGS-ST rate mitigation in the context of a global settlement of difficult revenue requirement and rate design issues, and with the realization that other rate design allocations also may not adhere to our traditional cost causation principles.

In assessing the reasonableness of the rate design results, we take some comfort from the fact that the Stipulation was entered into by representatives of small and large customer groups and the utility. Under the provisions of this Stipulation, each of these parties gave up some part of its litigated position in exchange for a certain result in the Stipulation. From the perspective of the litigants, it certainly appears that each has represented his constituency reasonably. Of course, we still must answer for ourselves whether from an overall public interest perspective the result is reasonable.

The issue, as Staff has ably observed, is whether in light of the sharp reduction in energy prices, soon to be reflected in the medium and large class standard offer rates and already available to many customers who are taking service in the competitive market, the original logic for the 8 mil mitigation that ends in March, 2002 still applies. If there is a basis for continuing some form of mitigation for anyone, it would be for those customers that executed contracts at a period of high prices for a multi-year period; their now relatively high prices carry forward into the new lower-price world. Such customers, however, likely are not limited to the LGS-T and LGS-ST classes. On its face, then the benefit seems both too broad – because it will go to some customers who have in fact done very well in the market, and thus for whom the price reduction is a mere windfall and not in any sense justified by the original logic of mitigation – and too narrow – because there are surely other industrial and commercial customers outside the T and ST classes who have contracts that will carry high generation prices well into next year but who are not included in the proposed price reduction. While we share the Staff's and Commissioner Diamond's concerns, for the reasons set forth below we believe there is sufficient justification for the mitigation provision to conclude that the provision does not poison the remainder of the Stipulation and cause us to reject the Stipulation in its entirely.

First, while we concluded in Docket No. 97-580 that allocating stranded costs on a 75/25 basis between energy and demand was an acceptable cost allocation methodology we have never mandated such a methodology. Docket No. 97-580, Order at 141 (March 19, 1999). In Docket No. 97-580, we based our rate design decisions on a "top-down" approach which tried to ensure that the overall rates on the bundled basis for all of the Company's customers paid would not increase at the onset of restructuring. We concluded that this "top-down" approach would facilitate the transition to a competitive market for generation and would best ensure the success of the electric utility restructuring at its implementation. Id. at 113. While we believe the state's restructuring effort has, on an overall basis, been a success and that Maine consumers are beginning to understand and accept the ramifications of a deregulated competitive generation market, we agree with the stipulating parties that the Commission should continue to be sensitive to the overall price that Maine consumers will pay for electricity in setting regulated T&D rates. Thus, overall bill impacts continue to be a factor, although reduced from the time of our initial decision in Docket No. 97-580, in designing T&D rates.

In this vein then, it is possible to view the 4.5 mil mitigation proposed here as a modest extension of the 8 mil mitigation we approved last year. At that time, we granted mitigation to a very wide range of customers because most, though undoubtedly not all, of those customers were faced with very sharp increases in energy prices. It seemed reasonable then to mitigate the impact of those increases by using a portion of the funds made available by the sale of the CMP assets (which, some might observe, may have been priced in anticipation of just such higher energy market prices), and to do so on a broad brush basis rather than a case by case examination of whether the particular customer was actually suffering economic hardship. While the evidence is weaker today, in that at least some of the customers targeted for the 4.5 mil reduction will be able to take advantage of the now lower energy prices, we think it is reasonable to conclude – and, in fact, it has been represented to us – that at least some of the customers in the T and ST classes continue to suffer the "hangover" of the higher prices for which we found mitigation to be appropriate last year. While a strict application of the 75/25 allocation methodology would produce a slightly greater rate than the rate design proposed by the Stipulation with mitigation, the result reached by the Stipulation is certainly within the rather broad range of justifiable results.

Finally, as we have noted on past occasions there is rarely one acceptable resolution to the issues raised in cases litigated before us. *Central Maine Power Company, Request for Approval of Alternative Rate Plan (Post-Merger) "ARP 2000*," Docket No. 99-666 Order Approving Stipulation at 16, (Nov. 6, 2000). While it might be attractive to try to target the relief more precisely to those individual customers who continue to have high energy prices, it is not obvious to us that by solving the "free rider" problem we do not create an equally nettlesome problem of inserting ourselves into the market as a backstop for poor or unlucky decisions made by customers who shop for power. If we target individual customers who have disadvantageous contracts, we diminish the importance of their own individual skills in the marketplace. Thus, we are faced with the Hobson's choice of paying some too much and others too little relative to their particular needs, or interfering with the discipline of the competitive energy market we are trying to encourage. While we may have designed a different mitigation program were we designing the program on our own initiative, we cannot not find the program adopted as part of the Stipulation to be unreasonable or contrary to the public interest. Furthermore, even though, if litigated, we may prefer to terminate the rate mitigation program we instituted last year, we find that the limited and targeted continuation of that program, adopted as part of a global revenue requirement and rate design stipulation, does not transform the Stipulation into an unreasonable resolution of the issues of this investigation.

Accordingly, it is

O R D E R E D

1. That the Stipulation entered into between Central Maine Power Company (CMP), the office of the Public Advocate and the Industrial Energy Consumers Group is in this matter and dated December 13, 2001 and (a copy of which is attached hereto[4]) is approved.

2. That CMP shall file rates in accordance with the terms of the Order Approving Stipulation. We delegate to the Director of Technical Analysis authority to approve such rates filed in compliance with the terms of this Order.

Dated at Augusta, Maine, this 15th day of February, 2002.

BY ORDER OF THE COMMISSION

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Raymond J. Robichaud
Assistant Administrative Director

COMMISSIONERS VOTING FOR: Welch
Nugent

COMMISSIONER DISSENTING: Diamond

[4] One of the exhibits attached to the Stipulation contains confidential information. We have included a redacted copy of that exhibit with the Stipulation attached to this Order. The original Stipulation with the confidential exhibit will be kept in the Commission files, subject to terms of the Protective Order.

NOTICE OF RIGHTS TO REVIEW OR APPEAL

5 M.R.S.A. § 9061 requires the Public Utilities Commission to give each party to an adjudicatory proceeding written notice of the party's rights to review or appeal of its decision made at the conclusion of the adjudicatory proceeding. The methods of review or appeal of PUC decisions at the conclusion of an adjudicatory proceeding are as follows:

1. Reconsideration of the Commission's Order may be requested under Section 1004 of the Commission's Rules of Practice and Procedure (65-407 C.M.R.110) within 20 days of the date of the Order by filing a petition with the Commission stating the grounds upon which reconsideration is sought.

2. Appeal of a final decision of the Commission may be taken to the Law Court by filing, within 30 days of the date of the Order, a Notice of Appeal with the Administrative Director of the Commission, pursuant to 35-A M.R.S.A. § 1320(1)-(4) and the Maine Rules of Appellate Procedure.

3. Additional court review of constitutional issues or issues involving the justness or reasonableness of rates may be had by the filing of an appeal with the Law Court, pursuant to 35-A M.R.S.A. § 1320(5).

Note: The attachment of this Notice to a document does not indicate the Commission's view that the particular document may be subject to review or appeal. Similarly, the failure of the Commission to attach a copy of this Notice to a document does not indicate the Commission's view that the document is not subject to review or appeal.

## DISSENTING OPINION OF COMMISSIONER DIAMOND

I dissent from the Commission's order approving the stipulation. Given the lack of support in the record for paragraph 15 of the stipulation (the "mitigation provision"), I do not believe the Commission can find the stipulation to be in the public interest.

Paragraph 15 of the stipulation provides that sub-transmission and transmission customers are to receive "mitigation of 4.5 mils per kilowatt hour ($.0045/kWh) for the rates in effect during the period from March 1, 2002, through February 28, 2003." The only justification offered is the conclusory statement that the mitigation given these customers is "in recognition of their current situation both within the Maine economy and their energy supply prices and contract terms." Since the revenue lost from mitigating the rates of these customers will be offset by a reduction in the asset sale gain account, there is a reasonable likelihood that all or most of the cost will effectively be borne by CMP's other ratepayers.

The mitigation provision is basically a transfer of wealth in an amount that is estimated to be $7.35 million. Although the provision applies to two rate classes, the number of beneficiaries is quite small. According to data provided by CMP, it is estimated that 71% of the money (or $5.7 million) will benefit just 11 customers. More broadly, 91% of the money (or $6.7 million) will benefit only 19 customers.

I see three possible rationales for the mitigation provision. I shall discuss them from the least to the most persuasive, indicating why I do not believe that any of them justify approving the stipulation based on the record in this case.

The first rationale would be that the mitigation provision compensates for benefits other ratepayers have received as a result of prior Commission actions. In this context, one could presumably point to benefits received by small standard offer customers by virtue of the Engage settlement and the fact that medium and large standard offer customers have paid somewhat more for standard offer service this past year than that service actually cost.[5]

While equalizing the benefits and burdens among different classes can be justified, the rationale does not fit this situation. The medium and large customers have already received compensation for the benefits received by

[5] This resulted from CMP's ICAP costs being lower than anticipated and the Commission policy of not reducing the established standard offer price during the term for which it was set.

small standard offer customers in the form of the 8-mil mitigation expiring February 28, 2002. More significantly, if one were to conclude that additional mitigation were appropriate on this basis, it should extend to all medium and large customers and not just to a subset of the latter group. In this case, those who are not among the chosen few not only do not receive the benefit, but they will wind up paying more because of it.[6]

The second rationale would be that by assisting this select group of customers we will be supporting the state's economy to everyone's eventual benefit. The problem is that there is absolutely nothing in the record to demonstrate that subsidizing this select group of customers with money that will come from all other customers, many of which are also businesses, will produce net benefits to the state's economy.[7] There is also no evidence that the recipients of the mitigation have a greater need than other industrial and commercial enterprises in Maine.[8]

On a more philosophical level, I have serious doubts that absent a legislative directive or extreme circumstances, the Commission should be in the business of transferring wealth to promote the greater welfare. This is the type of decision that should be made by or at the clear direction of an institution more directly accountable to the people. Perhaps because of the arcane nature of utility regulation, very few Mainers participate in our proceedings, and those who do generally have been litigating against, and negotiating with, each other for many years. In my view, transferring wealth in a free society in the name of the public good should be done by government's most accessible institutions, a description that does not fit the Commission, albeit through no fault of ours. My

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[6] Indeed, while the heading for paragraph 15 refers to "Mitigation for Certain Customers," that characterization reflects the vantage point of the beneficiaries. From the perspective of those who will pay more, the heading might more appropriately read "Surcharge for Certain Customers."

[7] Even if one assumes there will be benefits, the Commission did not even begin to consider the very complicated question of whether this is the most cost effective and most equitable means of protecting or promoting Maine's economy. Indeed, no other approaches were even considered.

[8] In preparing for the Commission's deliberation of this matter, I was able to locate financial statements for seven of the 11 principal beneficiaries of the mitigation provision or for their parent companies. Of those seven, six were profitable in the most recent quarter. While this is not dispositive of their need for assistance, as it does not indicate the health of their Maine operations, it does suggest that further analysis would be warranted before giving them a subsidy on the ground of economic hardship.

unease is only enhanced when we perform this function without a complete record to support our decision.

The third rationale would be that mitigation is necessary to soften the shock of recent high generation prices. As avoiding rate shock is a traditional feature of utility regulation, I find this the strongest theoretical justification for the mitigation provision.[9] Apart from the question of why price shock mitigation should be limited to just these two classes of customers, there is the additional problem that the record is devoid of any evidence of how much the beneficiaries of this provision are paying for generation or even whether that amount is greater than what is being paid by some of those who will be subsidizing them. In short, we run the risk, at least with respect to medium and large customers, of transferring wealth from those who are paying more for generation to those who are paying less.

This problem could be solved by requiring that a customer's generation price be above a certain level before the customer would be eligible for mitigation. If we are to take money from one group of citizens and give it to another on the basis of some defined need, we have an obligation to ensure that the recipients actually have the need. While individualized treatment may not be practical in many aspects of utility regulation, there is no reason why it could not work here, as we are dealing with a manageable number of potential recipients.

It has been argued that we need to make mitigation available to all sub-transmission and transmission customers because individualized treatment would result in rewarding those customers who made bad market decisions by entering into high-priced contracts. Accommodating this argument requires that we use ratepayer money to mitigate the high prices of those not paying high prices. This is simply squandering money. The argument also proves too much as its logical conclusion is to oppose any mitigation. Thus, at a minimum, the Commission should have rejected this stipulation with an invitation to the parties that they return with one that includes both criteria and procedures for determining eligibility.[10]

My position is not that using rates to mitigate high generation prices is always wrong, but rather that the specific provision in this stipulation is not

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[9] I recognize that mitigating high market prices is not the same as damping down regulated rates, especially for a Commission that places a high value on letting the market work. Nonetheless, it is analogous to preventing rate shock and can be justified as a reasonable transition measure as purchasers become accustomed to buying generation in the marketplace.

[10] This was done in the recent stipulation settling the stranded cost case for Bangor Hydro-Electric Company, Docket 2001-239, which is why I decided not to dissent in that case despite some discomfort with its mitigation provision.

supported by the record. For that reason, I suggested when this matter was deliberated that we reject the stipulation but indicate that we would accept it without the mitigation provision and that we would open a proceeding to determine if and for whom mitigation is warranted. At that proceeding, we would seek to obtain broader input, with a particular effort to solicit the views of those medium and large customers who are not covered by the stipulation. Although that proposal was rejected, I continue to believe it would have been a fairer way to deal with mitigation and would have provided us with a meaningful record on which to base a decision.

APPENDIX A

On May 8, 2001 the Commission issued a Notice of Investigation initiating this docket. That notice identified the likely issues to be addressed in this matter and also provided interested persons with an opportunity to intervene.

Timely petitions to intervene in this matter were filed by the Industrial Energy Consumers Group ("IECG"), Independent Energy Producers of Maine ("IEPM"), FPL Energy Maine, Inc. ("FPL") and Calpine Construction Finance Company ("Company"). An oral petition to intervene was made by the Office of the Public Advocate ("OPA") at the initial case conference held on May 23, 2001. The above-referenced petitions to intervene were all granted without objection.

In addition to the above-referenced petitions to intervene, the Commission received requests from Maine Public Service Company ("MPS") and from Bangor Gas Company, LLC ("Bangor Gas") that they be added to the service list in this case as interested persons and receive copies of all filings in this matter. CMP objected to Bangor Gas's request on the grounds that it had no interest in this case and that providing copies of data responses to Bangor Gas would be burdensome. Bangor Gas responded that it is a utility in the state and that while it is in a different industry, it will be facing many of the issues currently being considered in this matter.

By way of a procedural order dated May 29, 2001, CMP's objection was overruled and the requests of Bangor Gas and MPS to be added to the service list as "interested persons receiving all documents" was granted.

A teleconference to discuss scheduling in this case was held on June 5, 2001. Based on the discussions at the conference a schedule governing the first two phases of the case was established. As set forth in a procedural order of June 11, 2001, the Company's Phase I filing was to address:

1) Stranded cost class cost allocation methodology;

2) A proposal for the treatment of revenue from non-core customers;

3) A review of the operation of the QF incentive program since the close of Docket No. 97-580 and a proposal for an appropriate incentive mechanism on a prospective basis;

4) A comparison of budgeted nuclear expense figures used in the stranded cost calculations developed in the rate case to actual nuclear expenses;

5) An explanation of CMP's plans with respect to the HQ tie line;

6) CMP's Fall 2000 sales forecast for the three-year period 2001-2003 with a comparison to 2001 actual results;

7) A performance-based ratemaking proposal for resetting stranded cost prices and providing proper incentives;

8) An update of the ASGA balances including amounts amortized for targeted ASGA uses; and

9) Amounts deferred pursuant to the Commission's Order in Docket No. 97-580

As part of its Phase II filing, the Company was to address:

1) QF cost data and volumes;

2) Illustrative energy price placeholders for the sale of the purchased power entitlements;

3) CMP's Fall 2001 sales forecast;

4) Current data regarding CMP's nuclear obligations;

5) Updated information regarding the HQ tie line; and

6) CMP's approach for rate design using illustrative bid revenue and forecasted billing units.

The schedule for Phase III of the case, which would incorporate the actual results of CMP's sale of output from its non-divested generation asset and the standard offer bid process, would be developed at a later date.

On July 6, 2001, CMP submitted its Phase I filing in the case. A technical conferences on the Company's Phase I case were held on July 24, 2001 and on August 9, 2001. On August 16, 2001 the Advisory Staff and the OPA filed comments on the Company's Phase I filing. A technical conference to address the issues concerning the Company's buy-out of its power supply contract with RWS was held on September 27, 2001.

On September 19, 2001, Central Maine Power Company filed a letter with the Commission requesting a modification to the previously established schedule given the Commission's decision to accept a "linked" standard offer bid for residential and small commercial customer classes in Docket No. 2001-399. CMP argued that this decision obviates the need for a Phase III segment of the case and with the slight extension of time to file CMP could incorporate the standard offer and QF output prices into its filing. Bangor Hydro-Electric Company supported adoption of a similar revision in the schedule in Docket No. 2001-239.

By way of a Procedural Order issued on September 24, 2001, the requests of CMP and BHE to move the time for filing the utilities' Phase II case and the Phase I rebuttal from September 24, 2001 were granted. A conference of counsel to discuss the remainder of the schedule in these proceedings in light of the protective issues raised by the Commission's decision of September 18, 2001 in Docket No. 2001-399 was held on September 26, 2001. Under the terms of that protective order, access to such material is restricted to Commission members, Staff, members of the OPA and to the affected T&D utilities. The Examiners therefore concluded that the utilities, in developing their Phase II filings in this proceeding, should use proxy entitlement sale numbers (expressed in $/mWh) for purposes of calculating and allocating stranded costs.

On October 3, 2002, CMP submitted its Phase II filing using proxy prices established in the September 28, 2002 Procedural Order to calculate the revenue received from the sale of its non-divested generation entitlements. CMP's Phase II filing consisted of the testimony of Curtis Call/Paul Dumais (revenue requirement and rate design John Davulis (sales forecast), and Eric Stinneford/Roger Hanson (non-divested generation costs). A technical conference on the Company's case was held on October 30, 2001.

On November 13, 2001 the OPA filed its reply cases consisting of the testimony of Thomas Catlin and Steven Estomin. On that same date, the IECG filed the direct testimony of Richard Silkman and on November 14, 2001 the Advisory Staff filed its Phase II Bench Analysis. A technical conference on the Staff and Intervenor cases was held on November 29, 2001.

On December 7, 2001 the Company filed its rebuttal case consisting of the testimony of Call/Dumais, Stinneford/Hanson, John Davulis, and Davulis/Donihue.

On December 13, 2001 the Commission received a Stipulation entered into between the Company, the IECG and the OPA. On December 13, 2001 a hearing on the Stipulation was held. At such time, all prefiled testimony, the Staff's Bench Analyses, and all discovery including all transcripts of the technical conferences were admitted into the record. A post-hearing discovery conference was held on December 21, 2001 to clarify certain issues concerning the application of the stipulation's mitigation provision.

STATE OF MAINE )
PUBLIC UTILITIES COMMISSION ) Docket No.
2001-232
)
) December 13,
2001
)
MAINE PUBLIC UTILITIES COMMISSION )
Investigation of Central Maine Power Company's )
STIPULATION
Stranded Cost Revenue Requirement )
)

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Central Maine Power Company ("CMP"), the Office of the Public Advocate ("OPA"), and the Industrial Energy Consumer Group ("IECG") (collectively, the "Parties") hereby enter into this Stipulation in order to settle all remaining issues bearing on the above-captioned proceeding and thereby avoid further litigation.

***THE PARTIES TO THIS STIPULATION STIPULATE AND AGREE THAT:***

1. "An Act to Restructure the State's Electric Industry" ("Restructuring Act"), 35-A M.R.S.A. § 3208(6) (West 2001), requires the Maine Public Utilities Commission (the "Commission") to establish the recoverable stranded cost revenue requirement for each investor-owned utility at least every three years. In Docket No. 97-580, the Commission determined CMP's stranded costs for the rate effective period beginning March 1, 2000, through February 28, 2002. In this proceeding, the Commission is establishing stranded costs revenue requirements and rates beginning March 1, 2002.

2. Update for Actual Entitlement Sale Numbers. On October 2, 2001, in Docket No. 2001-399, the Commission entered an order (a) designating Constellation Power Source Maine, LLC ("Constellation") as the standard offer provider for the residential and small commercial class and (b) entitling Constellation to acquire the output from CMP's

nondivested generation resources for the period from March 1, 2002, through February 28, 2005. As part of that arrangement, the prices for the acquisition of the output from CMP's nondivested generation resources cannot be disclosed until on or after January 1, 2002. By Procedural Order in this docket, dated September 28, 2001, the Examiner ordered CMP to use certain specified proxy entitlement sales numbers for purposes of computing stranded costs during the litigation of this proceeding. Furthermore, in accordance with another Procedural Order, dated October 9, 2001, CMP is required to file actual stranded cost revenue requirements on January 3, 2002. The Parties agree that this filing will be postponed until January 15, 2002, at which time CMP will file both the updated stranded costs reflecting the Constellation entitlement sales amounts and actual retail rates to be implemented on March 1, 2002. Under the terms of this Stipulation, the only update contained in the stranded cost revenue requirement will be for the amounts to be paid by Constellation for the output of CMP's nondivested generation resources.

3. Rate Effective Period. The stranded cost revenue requirement and rates established in this proceeding will be for the three-year period beginning March 1, 2002, and ending on February 28, 2005. Hereafter, the terms "Rate Year 1," Rate Year 2," and Rate Year 3" shall mean the three years beginning March 1, 2002, March 1, 2003 and March 1, 2004, respectively.

4. Sales Forecast. For the rate effective period, the sales levels to be used in the calculation of stranded cost rates shall be as set forth in Table 1 below. These updated sales forecast numbers adjust CMP's original sales forecast filed by CMP witness John Davulis on October 3, 2001, for, among other things: the assumption that there will be no incremental savings from demand-side management programs in 2002, recognition of the effects of the

current recession on CMP's sales and an update to the projected price of electricity for purposes of computing price elasticities.

**Table 1: Settlement Forecast: Sales (mil. kWh) by Stranded Cost Period**

| Rate Year | Total Sales | Residential | Commercial | Total Industrial | Paper | Other Industrial | Lighting |
|---|---|---|---|---|---|---|---|
| **1** | 9,164.0 | 2,981.0 | 3,002.1 | 3,145.8 | 1,578.2 | 1,567.6 | 35.2 |
| **2** | 9,371.1 | 3,027.8 | 3,115.1 | 3,192.9 | 1,579.0 | 1,613.9 | 35.3 |
| **3** | 9,562.3 | 3,078.9 | 3,210.1 | 3,237.8 | 1,579.8 | 1,658.0 | 35.5 |

5. Adjustment of Stranded Cost Rates for Sales Volume Changes. The Parties recognize and agree that under 35-A M.R.S.A. § 3208(6) (West 2001), any person may petition the Commission at any time to adjust stranded cost rates for, among other things, variances between the sales forecast underlying the derivation of stranded cost rates and actual sales. Without implying any inference to the contrary, the Parties agree that requesting a prospective adjustment to stranded cost rates for sales volume variances will not be precluded by application of any principles of single-issue ratemaking. The Parties further agree that no such request may be filed by any of the Parties hereto before May 31, 2002, and no sooner than 90 days following any subsequent adjustment in stranded cost rates that occurs prior to the end of Rate Year 3.

6. Reporting Requirement. To ensure that the Commission can fulfill its obligations under Section 3208, CMP, beginning with the three-month period ending May 31, 2002, will file quarterly reports with the Commission detailing the level of its electricity sales as well as the amount of stranded cost revenue, from both core and non-core customers, during the immediately preceding three-month period as well as the prior

twelve month period to the extent included in the rate effective period. CMP will file each report within 45 days of the close of each quarter.

7. Starting Point Revenue Requirement. In its direct case, CMP projected the stranded cost revenue requirement for the rate effective period as follows:

**Table 2: Starting Point Revenue Requirement**
**Docket No. 2001-232**
**(in thousands of dollars)**

| | **Rate Year 1** | **Rate Year 2** | **Rate Year 3** |
|---|---|---|---|
| **Total Stranded Costs** | $139,765 | $149,833 | $153,583 |
| **Less:** **Stranded Cost Revenue from Noncore Sales** | 11,421 | 12,327 | 12,855 |
| **Core Rate Stranded Costs** | $128,344 | $137,506 | $140,728 |

This stranded cost revenue requirement calculation shall be adjusted as set forth in paragraphs 8 through 13 hereof.

8. Adjustment to Noncore Revenues for Anticipated Increase in Diesel Deferral Rate. The stranded cost revenue from noncore customers shall be increased by $621,000. $606,000, and $607,000 (and thus the revenue requirement from core customers shall decrease by a like amount) for the three rate years, respectively, to account for a 5 mil ($.005) increase in the price estimated to be charged to customers taking service under CMP's diesel deferral rate.

9. Prudency and Recovery of RWS Buyout Costs. The buyout of CMP's purchase power contract with Regional Waste Systems (RWS) and the purchase of replacement power to fulfill CMP's obligations under its contract with Engage Energy were

both prudent and the costs thereof shall be fully recovered by CMP. These costs will be recovered beginning March 1, 2002, over the remaining term of the original contract, rather than being recovered by an offset to the Asset Sale Gain Account ("ASGA") as proposed by CMP in its direct case. Accordingly, the stranded cost revenue requirement will decrease by $784,000, $725,000 and $666,000, respectively, for the three rate years.

10. Estimate and Deferral of Expected Hydro-Quebec Tie Line Revenues. For purposes of computing stranded costs for the rate effective period, it is assumed that CMP will receive $1,077,000 per year for each of the rate years from its entitlement rights in the Hydro-Quebec Tie Line. To the extent that actual receipts from any source (including, but not limited to, credits for installed capacity from the line or transmission revenues from the line) differ from this estimate, CMP shall defer any such difference (whether positive or negative) with carrying costs for treatment in the next proceeding in which stranded costs are set.

11. Return on Connecticut Yankee Investment. For purposes of computing the stranded cost revenue requirement, CMP will use six percent (6%) as its return on equity for its unamortized investment in Connecticut Yankee. This will reduce CMP's revenue requirement by $380,000, $321,000 and $278,000 for the three rate years, respectively.

12. Maine Yankee Adjustment. To reflect various changes to the recoverable amount of costs related to CMP's share of Maine Yankee costs, the amount of stranded costs (other than the deferrals provided for paragraph 20 in this Stipulation) shall be adjusted as follows:

**Table 3: Maine Yankee Revenue Requirement by Rate Year**
**(Dollars in Thousands)**

| | Rate Year 1 | Rate Year 2 | Rate Year 3 |
|---|---|---|---|
| **CMP Direct** | $25,218 | $24,573 | $23,621 |
| **Settlement** | 22,809 | 21,887 | 20,840 |
| **Difference** | $ 2,409 | $ 2,686 | $ 2,781 |

13. Standard Offer Overcollected Balance. CMP currently estimates an overcollected balance of $4.5 million in the medium and industrial classes standard offer accounts as of February 28, 2002. This estimate will be included in the ASGA for return to customers and will reduce the stranded cost revenue requirement by $1,410,000, $1,328,000, and $1,247,000 for the three rate years, respectively. To the extent this estimate is incorrect, CMP shall defer the difference (whether positive or negative) for recovery in a subsequent proceeding.

14. Stranded Cost Revenue Requirement. As a result of adjusting CMP's starting point stranded cost revenue requirement (shown in paragraph 7 above) for the three rate years and in accordance with paragraphs 8 through 13 above, the stranded cost revenue requirements for the rate effective period are shown in Table 4 below.

**Table 4: Stranded Cost Revenue Requirement – Rate Effective Period**

| | Rate Year 1 | Rate Year 2 | Rate Year 3 |
|---|---|---|---|
| **Total Stranded Costs** | $133,705 | $143,696 | $147,534 |
| **Less: Stranded Costs Revenue from Noncore Customers** | 12,042 | 12,933 | 13,462 |
| **Core Rate Stranded Costs** | $121,663 | $130,763 | $134,072 |

These numbers will be updated on January 15, 2002, to take into account the actual revenue to be received from Constellation, as described in paragraph 2 hereof. A schedule showing the stranded costs revenue requirement from CMP's direct case and the adjustments described in paragraphs 8 through 13 above is contained in Attachment 1 hereto.

15. Mitigation for Certain Customers. In recognition of their current situation both within the Maine economy and their energy supply prices and contract terms, customers eligible for service under the Company's LGS-ST and LGS-T rates shall receive mitigation of 4.5 mils per kilowatt hour ($.0045/kWh) for the rates in effect during the period from March 1, 2002, through February 28, 2003. In no event, however, shall this mitigation reduce any customer's stranded cost contribution below zero. CMP shall defer with carrying costs the amount of this mitigation for offset against the ASGA to the extent available or otherwise recoverable in stranded costs in the next proceeding in which stranded costs are reset. CMP shall calculate the amount of this mitigation using actual sales results.

16. Levelization of Stranded Costs. To prevent fluctuations in customers' rates over the rate effective period, the stranded cost revenue requirement will be levelized on a per class basis as shown in Attachment 2. The levelization approach used in Attachment 2 considers differences in stranded costs recovery rates and kWh sales changes for each of CMP's rate classes. These numbers will be updated on January 15, in accordance with paragraph 2 hereof. The annual amortization of the ASGA, including adjusting such amortization to levelized stranded cost recovery, is shown in Attachment 3.

17. Cost Allocation Among Rate Classes. Attachment 4 shows the allocation of the stranded cost decrease resulting from this settlement to rate classes. The expected

stranded cost decrease is allocated to residential and small commercial customers with one exception. In order to move Rates IGS-S and LGS-S closer to a cost-based allocation of stranded costs and in order to maintain the voltage level relationship between Rate IGS-S and IGS-P and between Rates LGS-S and LGS-P, some of the decrease in stranded costs is allocated to Rates IGS-S, IGS-P, LGS-S and LGS-P. These numbers will be updated on January 15, in accordance with paragraph 2 hereof.

18. Deferral Mechanism for Extraordinary Stranded Cost Variances from QF Output. The Parties recognize that, while the three and five year averages for computing the output and stranded costs from thermal and hydro QF facilities provide an accurate projection over time, the output and stranded costs from CMP's larger QF contracts can vary widely on an annual basis. Therefore, to protect both customers and shareholders from wide fluctuations in QF output and stranded costs on an annual basis, the following deferral mechanism is established. As shown in Attachment 5, a baseline of stranded costs for thirteen (13) QF contracts is established (the stranded costs for these contracts will be updated on January 15, in accordance with paragraph 2 hereof). If the stranded cost from any of these contracts is outside a deadband of six percent (+-3%) in any Rate Year, the Company shall defer the amount of stranded costs outside the deadband (whether positive or negative) and shall recover or return the deferred amount, with the accrual of carrying costs beginning at the end of the rate year that the deferral occurs, in the next proceeding in which stranded costs are adjusted. This calculation shall be made for each individual contract for each rate year and shall be reported annually at the same time that the report required by paragraph 6 hereof is filed.

19. QF Incentive Mechanism. To continue to ensure that CMP has an adequate

incentive to restructure QF contracts, the following sharing mechanism is approved. Customers will receive 80% of the savings accruing from any QF contract restructuring and CMP will retain the remaining 20% over the life of the restructured contract. Each time stranded costs are reset the savings for that stranded cost period will be established. For purposes of calculating the savings, total post-restructuring costs will be subtracted from total costs that would have been incurred had no restructuring taken place.

When stranded costs are established, stranded costs rates will include the post-restructuring costs (rather than the pre-restructuring costs) plus CMP's 20% share of the savings for that stranded cost period. In the event that, for any stranded cost period, post-restructuring costs exceed pre-restructuring costs, no savings (positive or negative) will be included in rates. When a contract is restructured and until stranded costs are reset, 80% of the net savings calculated above will be deferred for future return to customers.

If and to the extent that any savings are derived from securitization, this sharing formula will not apply and, instead, customers will receive all the savings from any restructuring financed through such securitization.

20. Future Deferrals. The Parties stipulate and agree that, in addition to the deferrals already described, CMP shall defer with carrying costs for later offset against the ASGA or inclusion in rates the following costs, to the extent prudently incurred, which are not included in the determination of stranded costs in this proceeding:

A. For the rate effective period, any difference between the actual prices paid to United American Energy Corp. under the purchase power agreement and the prices assumed in setting rates in this proceeding.

B. For the rate effective period, any difference between the actual costs and revenues under the SAPPI Somerset purchase power agreement and the costs and revenues assumed in setting rates.

C. Any difference between the actual deferral amount during the period March 2000 through February 2002 and that included in CMP's direct case for SAPPI Somerset.

D. For the rate effective period, amounts of environmental remediation costs related to the divested generation assets to the extent not already recovered in rates or through reduction of the ASGA.

E. For the rate effective period, amounts for other costs or refunds related to the divested generation assets to the extent not already recovered in rates or through reduction of the ASGA.

F. For the rate effective period, any difference between the amount included in rates and the actual amount paid to any qualifying facility relating to the price paid to that qualifying facility which sells power to CMP under a so-called orphan decrement contract.

G. For the rate effective period, any amount paid to Miller Hydro with respect to any payment actually made with respect to any claim for payment of value for Installed Capacity.

H. For the rate effective period, any change in the amount of nuclear decommissioning payment made with respect to either Maine Yankee or Connecticut Yankee.

I. For the rate effective period, any payments made with respect to Maine Yankee's obligations under the so-called Texas Low Level Waste

Compact or with respect to the Spent Fuel Trust.

J. For the rate effective period, any amounts received by CMP with respect to its lease of the Cape Station facilities.

K. For the rate effective period, any net difference between stranded costs set in this proceeding and actual stranded costs relative to Vermont Yankee, including the impact of the sale of the plant (the difference between CMP's share of sales proceeds and CMP's investment), any remaining post-sale costs, the stranded cost impact of any delay in the actual closing date beyond March 1, 2002, and the results of negotiations with Secondary Purchasers.

CMP retains at all times the responsibility for demonstrating the prudency of each of these items prior to recovery or adjustment in rates.

20. The execution of this Stipulation by any Party shall not constitute precedent as to any matter of law or fact nor, except as expressly provided herein, shall it foreclose any of the Parties from making any contention or exercising any right, including rights of appeal, in any other Commission proceeding or investigation, or any other trial or action.

21. The Parties intend that this Stipulation be considered by the Commission for adoption as an integrated solution to the issues addressed herein which arose in the above-captioned proceeding and as otherwise presented in this Stipulation. The Parties also intend that this Stipulation shall be null and void, and shall not bind the Parties in the above-captioned proceeding, in the event the Commission does not adopt this Stipulation without material modification.

22. If not accepted by the Commission in accordance with the provisions hereof, this Stipulation shall not prejudice the positions taken by any Party on these issues before the Commission in this proceeding and shall not be admissible evidence therein or in any other proceeding before the Commission.

23. The record for purposes of consideration of this Stipulation shall include: all pre-filed testimony, Bench Analyses, transcripts, and data responses submitted by all parties.

Dated: ________________ CENTRAL MAINE POWER COMPANY

By: ________________________________

Dated: ________________ THE PUBLIC ADVOCATE

By: ________________________________

Dated: ________________ INDUSTRIAL ENERGY CONSUMER
GROUP

By: ________________________________

Dated: ________________ INDEPENDENT ENERGY PRODUCERS
OF MAINE

By: ________________________________

Dated: _______________ S. D. WARREN COMPANY

By: ________________________________

Dated: _______________ FPL ENERGY MAINE, INC.

By: ________________________________

Dated: _______________

CALPINE CONSTRUCTION FINANCE COMPANY

By: ___________________________________